

# Forward Contracts in Electricity Markets: the Australian Experience

Edward J Anderson and Xinmin Hu

Australian Graduate School of Management

University of New South Wales, Sydney, NSW 2052, Australia

Donald Winchester

Faculty of Commerce & Economics

University of New South Wales, Sydney, NSW 2052, Australia

**Abstract** Forward contracts play a vital role in all electricity markets, and yet the details of the market for forward contracts are often opaque. In this paper we review the existing literature on forward contracts and explore the contracting process as it operates in Australia. The paper is based on interviews with participants in Australia's National Electricity Market. The interviews were designed to understand the contracting process and the practice of risk management in the Australian energy-only pool market. This survey reveals some significant gaps between the assumptions made in the academic literature and actual practice in the Australian market place.

## 1 Introduction

Wholesale markets for electricity are complex, and their structure varies from one country to another. However, they have in common the characteristic that spot prices for electricity are highly volatile. This is a consequence of the inability to store electric power at any significant scale, so that power consumption and generation need to match each other very closely. Electricity demand is highly variable (e.g. with time of day and weather) and the volatility in price is exacerbated by the way that consumers are usually charged a fixed retail price independent of the spot market price. In this situation various types of generator reserves play an important role in ensuring stability of supply, with the necessary balancing role being

played by a ‘system operator’ who has the ability to dispatch generation. The system operator also needs to manage the network requirements, solving power flow problems in the network and taking account of transmission constraints.

Within this framework, forward markets play a crucial role. At one level, market participants need to engage in bids and offers in advance of real time simply to enable the system operator to look ahead and ensure physical feasibility of the proposed schedule. At another level, the forward markets provide a way for participants to manage the risk associated with the inherent volatility of the spot market. In this paper we will focus on forward markets for energy, though forward markets may also exist for reserves, for transmission capacity and for greenhouse gas emissions (or environmental products).

Many markets contain a provision for day-ahead trading. This time frame is a natural one since it enables the system operator to plan against congestion on major transmission lines and also gives generators the opportunity to plan on a daily basis taking account of unit availability and constraints as well as predicted demand. The day-ahead market often takes place through an exchange - which is the natural form when contracts are made with a market manager, rather than bilaterally. The market manager then balances aggregate demand and supply<sup>1</sup>. But a day-ahead exchange is not a necessary part of the structure of an electricity market; and there is no equivalent to a day-ahead exchange in Australia.

Bilateral trades between generators and retailers (or large consumers) are the dominant form of forward trading in electricity markets. But bilateral trades can also take place between generators or with other intermediaries. Markets differ in whether forward contracts are physical or purely financial. With a physical contract a generator makes a commitment to provide a certain amount of electricity. If the generator is not able to do so when it comes to real time then it will have to purchase the additional power in the spot market. Under this arrangement the spot market only accounts for a proportion of the power actually consumed. With financial contracts the payments under the contract are made in addition to the payments for power, but are linked to the spot price. With these contracts all the power consumed is traded through the spot market. When the spot market accounts for all the trade in wholesale electricity, it is called a ‘gross pool’; as opposed to a ‘net pool’ in which only the residual demand is traded, with bilateral forward trades netted out. A net pool is a type of

---

<sup>1</sup>In PJM, the PJM ISO operates the day ahead scheduling market; in Nord Pool, Nord Pool Spot AS operates a day ahead spot market; in Texas, ERCOT operates a day ahead balancing market (although adjustments are allowed up to one hour ahead).

real-time balancing market.

The standard financial instrument for forward contracts in electricity markets is a swap (sometimes called a ‘contract for differences’ in this context). The contract is for a particular quantity  $Q$  at a strike price  $f$ , which simply represents the agreement of the retailer (or buying party) to pay the generator (or selling party) an amount  $\$(f-p)Q$  after the spot market price  $p$  is determined. If the spot market price ends up being higher than the strike price then the retailer will receive money from the generator rather than the other way around. In some ways the difference between a physical contract and a financial swap contract is not very great: the payments made between the parties are equivalent.

There are many ways in which market structures can be set up, and this includes the arrangements for forward contracts. This is particularly true for a net pool. For example, in the former California market (where long-term contracts were not allowed) and the Nordic electricity market, a centralized auction market (Power Exchange Market) trades contracts with contract time windows from a day ahead to a few months ahead, or longer. While in the current markets in both England and Wales and California, bilateral contracts are signed without any system operator involvement. In these markets, buyers and producers are forced to enter into contracts. However, in gross pool markets such as Australia, contracts between market participants are voluntary. Both in the UK and California, the system operator runs a balancing market which has relatively low volume: in the UK, it is about 5% of the total delivery and in California, less than 10%.

Bilateral contracts may operate over a long period of time. For example, Australia and some other countries like the UK, that have privatized publicly owned generating capacity, chose to put in place so-called ‘vesting contracts’ for a large part of the generation capacity in advance of selling the generation assets. These have the aim of reducing the risk to purchasers of privatised assets in the context of a newly created market for electricity. These contracts are in the form of swaps to run for a number of years (in Australia these have now expired). Also contracts for the provision of power to industries such as aluminium smelters have often been signed over periods of many years, particularly at the time when smelting capacity is constructed. Nevertheless the typical length of time that a contract runs is either for a quarter or a year, with many contracts signed one or two years ahead of time. Long-term contracts clearly carry a large risk that the market environment changes substantially leaving one or other party at a severe disadvantage. For example when California faced its energy crisis, the

state government changed the market rules and signed a number of long-term contracts with generators to ensure adequate supply. However, in retrospect it is clear that it bought too much at too high a strike price and this led to the requirement to renegotiate these contracts.

Long-term contracts have an important role in the entry of new participants in the market, and particularly when new generation capacity has to be built. On the one hand, retailers can sign long-term contracts with a new generator entrant to ensure a stable and forecastable cash flow to the investors, which will therefore make the investment decision less risky and facilitate new entry. On the other hand, incumbent generators can use their long-term contracts to deter entries (see Newbery (1998)); as we will see below, high contract levels can lead to lower spot market prices and make the market unprofitable to new entrants.

A comparison with trade in other commodities might lead one to expect there to be active secondary markets in various types of traded financial instrument. However in many electricity markets there is relatively little secondary trading activity. During the 1990's trade in energy derivatives was widely expected to increase as electricity markets around the world matured, however in most markets growth in volume has been slow. There are a number of possible explanations. First the collapse of Enron in December 2001 may have had a dampening effect on such trading activity. Enron was a major participant in a number of derivative markets (see Energy Information Administration Report (2002)). Secondly the important role of generators themselves in trading in electricity markets and at the same time in determining prices in the primary market increases the risk for speculators in comparison with other commodity futures. This is related to the competitiveness of the underlying physical (spot) market (see Energy Information Administration Report (2002) and Eydeland and Wolyniec (2003)). Certainly there are relatively few speculators operating in electricity forward markets, in comparison with the retailers and generators who are participants in the primary market. Thirdly the relatively recent introduction of many energy markets, coupled with the extraordinary importance of electrical power in national economies and citizen's lives, have meant that regulators have frequently changed the rules for the operation of these markets. Speculators may feel that the significant degree of regulatory risk make electricity markets less attractive.

The market for bilateral contracts is often referred to as an over-the-counter (OTC) market. Another important form of forward contracting takes place in a futures exchange. There is evidence that some exchanges have had problems because of the reluctance of speculators

to engage in trading on such exchanges. For example, Moulton (2005), in his analysis of the failure of the market for Californian electricity futures traded on NYMEX, argues that speculators leaving this market was the key factor in its demise, since hedgers alone did not provide enough activity to give appropriate hedge cover in all circumstances.<sup>2</sup>

There are many issues in relation to forward markets for electricity that are not well-documented, particularly in respect to the OTC contract market. For example, how do market participants use contracts in their risk management? What factors do they consider in negotiating contracts? How do they select contract counter parties and what form do contract negotiations take? This paper tries to answer some of these questions for the Australian market and in so doing fill some of the gaps between academic discussion in this area and actual practice. The paper is organized as follows: We begin by giving a general discussion of the connection between the forward and spot markets. Then section 3 introduces the Australian National Electricity Market and electricity derivatives markets. Section 4 presents our survey results based on interviews with retailers, generators, brokers and intermediaries. Finally, in section 5, we conclude with a discussion of some of the important trends in this market.

## 2 The connection between forward and spot markets

The existence of forward contracts changes the behaviour of generators in the spot market. Across a range of different market structures, a player who already holds a contract for some part of their possible production will choose to offer at a lower price in the spot market (or if the spot market has a Cournot structure, offer a greater total quantity). Because a firm's optimal reaction function is more competitive if it holds a forward contract, in equilibrium this results in a lower price in the spot market.

As an example of this we briefly describe the simplest case where two symmetric firms ( $i$ ,  $j$ ) compete in a Cournot spot market (as in Allaz and Vila (1993)). Suppose that demand is linear and units are normalized so that the price in the spot market is given by  $p = a - q_i - q_j$  when the generators offer  $q_i$  and  $q_j$ . If the costs of production are fixed at  $c$  per unit and player  $i$  holds an existing contract for an amount  $Q_i$  at a price  $f$ , then the profit function for

---

<sup>2</sup>NYMEX started electricity futures contract trading in April 1996, but it delisted all five products for electricity futures contracts in February 2002 due to lack of interest.

player  $i$  is

$$\pi_i(q_i, q_j) = (a - q_i - q_j)(q_i - Q_i) + fQ_i - cq_i.$$

Thus the optimal choice for the quantity sold for generator  $i$  is

$$q_i = \frac{a - c + Q_i - q_j}{2},$$

so that  $q_i$  is increasing with the contract quantity  $Q_i$ . With this arrangement we reach an equilibrium price in the spot market of

$$p = \frac{a + 2c - Q_i - Q_j}{3}$$

Bushnell (2005) extends this result to the case of  $n$  firms with quadratic cost functions.

The nature of electricity spot markets is not particularly well represented by a Cournot model. A more realistic representation includes the fact that generator offers will take the form of a schedule of prices and quantities. This has led to the application of supply function equilibrium ideas introduced by Klemperer and Meyer (1989). Green (1999) shows that, when supply function offers are restricted to be linear functions, an analysis similar to the above can be carried out linking the equilibrium outcome to the amount of contracts held by both generators. The conclusion is the same as drawn by Allaz and Vila – the existence of contracts will reduce the price in the spot market. Wolak (2000) also discusses the reasons for this result in a general context.

The majority of work in this area has assumed that, if the players are risk neutral, then the price for contracts will be the same as the expected price in the spot market. With this no-arbitrage assumption the generator profits are reduced as a result of holding contracts and a question arises as to why generators should enter into forward contracts at all. Allaz and Vila argue for a type of prisoner's dilemma behaviour in their model. If just one of the two firms enters into a forward contract then doing so will enable him to make greater profits (at the expense of the other player). However when both players enter into contracts both are worse off. When considered as a two player game, where each player chooses to contract or not, then the only equilibrium has both players choosing to enter forward contracts. Green (1999) shows that, with the slightly different structure arising from supply functions, the result will depend critically on the conjectures that firms make about their rivals behaviour in the contract market. If a firm assumes that taking up a contract will reduce the total contract cover of its rival, then it will sign forward contracts; but if a firm assumes that its behaviour in the contract market has no effect on the rivals contract cover, then it will not do so.

There is some controversy over whether, in a risk neutral context, we may expect forward prices to match spot prices in expectation. Powell (1993) introduces a model in which this does not occur, and Anderson and Hu (2005) argue that in electricity markets there will exist a strategic premium to encourage generators to sign forward contracts, given the negative impact of forward contracts on the generators' market power in the spot market. This opens up at least the theoretical possibility of a "free rider" effect. Since forward contracts increase competition among generators in the spot market, the spot market price will be lower than when the contracts were not signed. Therefore, those retailers or users who have entered contracts with generators will have paid a (high) contract price to bring the spot market price down and those who do not contract will benefit from the lower spot market price without incurring any cost.

There is also considerable uncertainty about the exact process by which bilateral contracts are negotiated. In fact researchers in this area have made different assumptions about the process of contract negotiation. In Powell (1993), the contracting process is modelled by assuming that generators decide the contract price and then retailers decide the contract quantities. However the opposite is assumed in Green (1999) in the contract stage, where generators and buyers of the contracts determine the contract quantities and contract prices respectively. While in Anderson (2004), both the contract and the spot markets are modelled as centralized auction markets where generators bid in the form of supply functions.

In practice the dominant motivation for contracts is that they fulfil a hedging role, to enable participants in the market to reduce their risk, given highly volatile prices in the spot market. Here the generators and retailers form natural hedging counter-parties: a forward contract serves to reduce the risk for both of them. In addition we might expect that in these markets there would be opportunities for risk averse players to sign contracts with speculators (risk takers). In this environment risk averse players pay risk premiums to enter contracts with other parties and transfer some risk to the sellers of the contracts.

Bessembinder and Lemmon (2002) consider a model with a competitive spot market in which participants have mean-variance utility functions. They also look at empirical data on the difference between spot and forward (one month ahead) prices for both PJM and the Californian market. Empirical relationships between the forward market and spot market are examined in Lucia and Schwartz (2002) for the Nordic Pool; and by Shawky and Barrett (2003) for the wholesale prices at the California-Oregon Border (COB) and the NYMEX

futures prices for electricity delivered at COB.

### 3 Australian National Electricity Market

The Australian National Electricity Market (NEM) started its operation in 1998 with four states: New South Wales (NSW), Victoria (VIC), Queensland (QLD), and South Australia (SA), together with the Australian Capital Territory (ACT). The fifth state, Tasmania (TAS) joined the NEM in 2005 (though a physical link will only occur when the Basslink is completed). The NEM is a mandatory gross pool market. Any units with capacity more than 30 MW must sell their generation through the NEM and the sales and purchases are settled at the corresponding six regional reference prices (see Figure 1 for the market nodes and inter-regional transmission links). Dispatch is carried out to minimize the total generation cost based on the offers from generators, subject to network and system constraints. The system operator is NEMMCO. The NEM processes are governed by National Electricity Rules and regulated by a number of federal regulatory bodies. Other matters, like distribution and environmental policy are regulated by state jurisdictions.

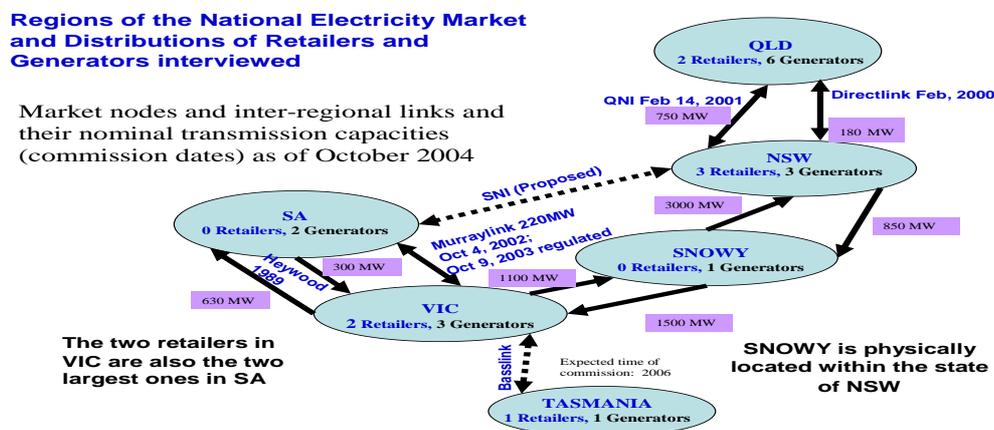


Figure 1: Market regions and inter-regional links of the NEM

Table 1 summarizes some facts about the NEM. The number of retailers listed in each region refers to those based in that region and having franchise customers there. However most retail companies have licenses to sell electricity to contestable customers in different states. The retail price for those customers who have not become contestable is regulated by the state jurisdictions. Most of the generation businesses are independent of the retail sector. The ownerships of generation and retail businesses are quite different from region to region.

In Victoria, all generation and retail businesses are privately owned. In NSW, the three major generators and the three retailers are publicly owned. QLD and SA have mixed ownerships.

The peak load in Table 1 refers to the highest load that occurred in the region during the period from 1998 to 2005. The annual consumption in the NEM is about 165,000 GWh (as a comparison the UK market is about twice as large, and the PJM market is about four times as large.)

Region	large generators	retailers <sup>a</sup>	installed capacity (MW)	peak load(MW) <sup>b</sup>	Fuel mix
NSW	3	3	12461	13032	coal
VIC	4	3	8528	8572	coal, gas
QLD	5	2	10200	8176	coal, gas
SA	3	4	3656	2832	gas, coal, renewables
TAS	1	1	2549	1672	hydro
SNOWY	1	0	3676	20	hydro

Source(except otherwise specified): NEMMCO's *List of generators and scheduled load, version November 15, 2005*

<sup>a</sup>Information is based on the corresponding State Regulators' websites visited in December 2005

<sup>b</sup>Information from *An introduction to Australia's national electricity market, NEMMCO, June 2005*

Table 1: Basic facts about the NEM: generation and retail

Another important factor in the NEM is that the fuel for generation (coal, natural gas) is supplied locally and hence is less influenced by volatile international fuel markets, which makes the participants' risk management simpler.

### 3.1 The operation of the spot market

Generators submit dispatch offers of up to 10 incremental price-quantity pairs for each of their generation units to NEMMCO before 12:30pm for each of the 48 half-hours of the next trading day, which starts at 4:00am. Prices must be below the price cap which is currently \$10,000/MWh<sup>3</sup> (throughout this paper the dollar symbol will refer to the Australian dollar). NEMMCO does pre-dispatches on a half-hour basis using the dispatch offers and the forecast load, and this pre-dispatch process continues until the real-time dispatch. The pre-dispatch outcomes are immediately available to the market participants. This provides more accurate market information to the participants and generators are allowed to modify the quantity bid at each price in good faith. There are rebidding rules, but they do not specify precisely the generator behaviour that is forbidden. A significant proportion of the rebidding reasons

<sup>3</sup>However different arrangements come into play if the sum of the spot price in a region for the previous week exceeds a cumulative price threshold (currently AUD\$150,000).

submitted to NEMMCO by generators are related to their contract positions (see Hu and Batten (2005)).

The real-time dispatch takes place as in the pre-dispatch model except for the use of real-time network conditions and more accurate load targets. The real-time dispatch is on a 5-minute basis. In each of the 5-minute periods, a price for each region is determined by minimizing the generation cost to meet the load. The market clearing price (RRP) for each region is the average of the six 5-minute prices. Generators are paid and retailers are charged the RRP for the half hour (modified by loss factors according to their location relative to the reference node in their region).

### 3.2 Secondary financial and emissions trading markets

Electricity prices in pool markets around the world are one of the most volatile of commodity prices (see Energy Information Administration Report (2002), Eydeland and Wolyniec (2003)). Price spikes occur because of variations in demand (often as a result of weather conditions since much demand is temperature-driven) and outages of generators or transmission lines. This is compounded by generator bidding behaviour. So it is not surprising that various electricity derivatives are traded to manage the financial risks for market participants.

Currently in Australia there are three types of forward trading activity, and we describe these briefly here.

- **Bilateral OTC trades negotiated directly between the two parties.** The contract counter-parties negotiate the terms and the structure of the contract. This flexibility is valuable in matching the particular hedging requirements of the participants. OTC trades can be based around swaps or involve option contracts.
- **Bilateral OTC trades on standard products executed through brokers using screens.** The electricity derivatives traded through brokers are swaps, and standard option contracts (primarily caps, but also floors, swaptions, and Asian options). Prices for these products are shown on the screens and participants are able to agree the contract price electronically. At this point a participant discovers who the counter-party is and completes the contract with a bilateral agreement. There are about 6 brokers in the electricity OTC markets, who charge a commission fee for a contract they have facilitated, but do not have an interest in the contract itself.

- **Derivative products traded on the Sydney Futures Exchange (SFE)**<sup>4</sup>. A number of standard contracts are sold as futures, with the resultant need for participants to pay (daily) margin calls over time once the futures contract is agreed. The two key advantages of this form of forward trading are that the trade is entirely anonymous and the use of margin calls mean that credit risk is essentially eliminated. D-cyphaTrade operates an electricity trading facility on the SFE, where electricity futures contracts have been traded since 2002. The types of products have changed over time. There has been significant growth of futures volume over the last year and the trading volume in the 12 months to February 2006 covered about 22%<sup>5</sup> of the physical energy in the NEM.

The OTC brokers and exchanges have a valuable role within the market: they bring trading partners together; operate screen systems; and provide data and other specialist services.

In addition to trades in the forward market being made by (physical) market participants, there are a number of market traders who do not have either generation facilities or energy consumers; sometimes these are called intermediaries. But according to some participants, only two significant market intermediaries were active at the time of the interviews.

A complicating factor in the forward markets are State-based schemes introduced to protect retailers from pool price volatility. The NSW government set up the Electricity Tariff Equalization Fund (ETEF) in 2001. This provides a type of swap contract for the non-contestable load (the franchise customers), but the strike price is the regulated tariff determined by the NSW Treasury. Under this arrangement retailers contribute to the fund whenever spot prices are lower than the regulated tariff for franchise customers, and they are paid from the fund when the reverse is true. In the event that the fund falls to a low level, NSW generators are called on to pay into the fund, according to their relative generation proportions. The volume of demand covered by ETEF has slowly reduced as retail competition has removed franchise customers.<sup>6</sup> Queensland operates long-term energy procurement arrangements with a similar aim to ETEF, but this scheme works in a different way since generators are not involved. Pay-

---

<sup>4</sup>In addition to the SFE, the Australian Stock Exchange has also operated a futures market. The participants we talked to did not use this exchange - it seems to be no longer active.

<sup>5</sup>According to d-cyphaTrade's Energy Focus, Issue 6, February 2006

<sup>6</sup>In 2003, ETEF covered 33% of the NSW demand according to Australian National Competition Council: 2003 Assessment of Governments' Progress in Implementing the National Competition Policy and Related Reforms.

ments are made to retailers from the Queensland Treasury for community service obligations - to support a uniform retail price for electricity, but retailers pay the Treasury in the event that their revenue exceeds expenses.

In addition to forward trading based on the spot price of electricity there is an increasingly important role for the trading of environmental instruments in the Australian market. The Australian Commonwealth Government has introduced a Mandatory Renewable Energy Target requiring retailers and large electricity consumers to purchase 2% of their total electricity from renewable energy sources or waste-product sources by 2010, or otherwise pay \$40/MWh penalty for the obligated amount. An OTC traded renewable energy market started in 2001 to trade Renewable Energy Certificates. The State Governments also have their own policies to control or reduce greenhouse gas emission. These schemes have encouraged new generation from renewables. Retailers have usually signed long-term power purchase agreements (PPAs) with the developers of these projects.

## 4 Contract trading in the NEM

In this section we will describe the practice of forward contract trading in the NEM. The information we give is based on 26 interviews with market participants, carried out during the period from October 2005 to December 2005. There were 8 interviews with retailers (some with significant generation capacities), 16 with generators, 1 with a market intermediary (Westpac—an investment bank group), and 1 with a broker in the OTC market. The interviewees were in most cases the general manager of the trading team for their companies. Many of the issues discussed were commercially sensitive and we will not report precise figures or identify individual companies in this paper.

The interview questions were designed to explore:

- the features of contracts in their business (contract types, time scale, proportions of contracts traded through brokers, use of the futures exchange, etc.);
- the contracting process (setting the contract price, contract initiation, contract counter parties, etc.);
- the appetite for contracts (tools for tracking risk, issues involved in determining contract levels, adjustment of contract cover, relation between contract prices and spot prices, etc.).

## 4.1 Risk attitudes and risk management

The financial risk to market participants arises from uncertainties with respect to both price and volume. A retailers' revenue is at risk if the spot price is very high and there is high consumption from end-users paying a fixed tariff. A cautionary example is the bankrupted load serving utilities in California in 2001 (see Borenstein (2002)). On the other hand a generator may be in trouble if the market price is too low (cannot recover investment cost) or if there is a price spike and at the same time the generator cannot meet the contracted amount due to equipment failures (for example, the bankrupted generators in the Midwest region of the US in June 1998 (see Michaels and Ellig (1999))). From the trading side, the credit risk of trading counter-parties is a great concern. OTC trades through brokers make it hard to appropriately price in credit risk, since prices are settled before the counterparty to the trade is identified. Finally we should mention that there are longer run uncertainties arising from regulatory risk.

Risk management is a centerpiece in all retail and generation businesses, who have well-established policies and procedures to manage risks, and implement trading strategies within the limits set by these policies. Market participants mentioned many different tools they use to monitor risk. These include value at risk (VaR) at various time windows (e.g., daily, weekly), stress testing (scenario simulation methods), earnings at risk, capital at risk (cash value at risk), and mark-to-market methods. The most often quoted methods were VaR, earnings at risk and stress testing. Typically risk limits are very closely monitored on a daily basis. For similar practices used in other countries, see Pedersen and Mo (2005) who used a questionnaire survey involving 37 companies from 18 countries.

Most retailers described themselves as (very) risk-averse. However, the attitude to risk and the risk management methods used may differ substantially from one company to another, especially between the State government owned businesses in NSW and QLD and the privately owned companies in SA and VIC. In general the government owned businesses are more risk-averse than the private companies. This may be a result of governments having more conservative risk attitudes. For example, the NSW Treasury has shown some concern about energy trading risk for its electricity businesses (NSW Treasury (2001)).

The majority of market participants operate both a 'hedge book' and a 'trade book'. Contracts in the hedge book are purely for the purpose of offsetting risks, while the trade book gives room for their risk management or trading team to try to make a profit from

these contracting activities. Often, the trade book is more closely monitored than the hedge book and the proportion of contracts in the trade book could be quite small, depending on the company's risk appetite. Operating a small trade book may also help in making better decisions on the larger hedge book, as one participant put it: *"We believe that if you are active in the market then you are going to understand who is doing what and what prices are out there"*.

## 4.2 The mix of contracts held

In this section we will give more details on the mix of forward contracts used by participants. We start by considering the direct bilateral trades. Longer term contracts can be for periods of between 5 and 25 years. Some retailers and generators have inherited long-term contracts from their parent entities or predecessors<sup>7</sup>. Where generators mentioned these contracts they were always 'out of the money'. A second type of long-term contract may exist between generators and large industrial users, such as aluminium smelters (consuming more than 10% of the NEM generation), pulp and paper, cement and glass industries. Also long-term contracts are necessary to ensure funding when significant new generation capacity is built. In some cases this funding is through PPAs (e.g. for wind power which is sold through the NEM but not dispatched through it), in other cases there are conventional swaps or caps that run over many years..

Overall direct bilateral trades are the largest part of the forward market: the interviews suggest that this form of contract accounts for about 50-60% of the total. But there is wide variation around this figure, with one generator saying that the direct bilateral deals now account for only 20-30% of its total contracting, while at the other extreme one of the retailers said that it does more than 90% of its total contracting in this way.

The majority of customized bilateral contracts may be described as medium-term and are for less than 5 years. Most of these contracts are hedging contracts between retailers and generators (which we discuss in more detail below). However generators also reported that they have contracts with other generators: for most this is a small part of their portfolio, but one reported that more than 20% of its total contracts were with other generators. The

---

<sup>7</sup>For example, the Annual Report (2001, page 24) of the former Edison International, now IPM Australia Limited, owner of generating units in Victoria, Australia, states that it has entered hedge contracts with the State Electricity Commission of Victoria, selling 77% of its plant output under contracts commencing May 1997 and terminating in August 2014.

position has become less clear cut as retailers, especially in Victoria, have begun to vertically integrate by buying generation capacity.

On occasion medium-term contracts are set up for a particular customer's load. However the normal practice is for a retailer to combine the load from different commercial customers and look for contract cover for the full amount, rather than making many separate contracts as new business is won.

The second component of the contract market are OTC trades made through brokers. These contracts are for the shorter term, less than 3 years, with the greatest liquidity 1 year ahead or less. The overall picture was that OTC trades through brokers accounted for about 40% of the total, but again there was a large variation between individual participants with one (generator) reporting that up to 70% of recent trades were through brokers. This part of the market has clearly become more important over the last few years, with significantly more trades being made in this way and good liquidity especially in the near term (next calendar year and next quarter). This is the market in which participants adjust their contract cover as more information on demand becomes available to them (sometimes this is driven by the need to stay within risk limits).

However exactly the same issues occur even at shorter time horizons of days or weeks. For changes in contract cover in the very short-term there is no liquidity available through brokers (or through the SFE) and participants will approach possible counter-parties directly. But this may result in an unacceptably high price, so these very short-term trades are comparatively rare.

The third component of the market are futures contracts traded in the SFE. This is the smallest part of the overall contract market, with some generators saying that they make no use of the SFE, citing either the lack of liquidity, or difficulties with margin calls on a daily basis <sup>8</sup>. For the participants we spoke to who use the futures market, it appeared that around 5% of their total trades were through the SFE, with the largest reported percentage being 15%. The anonymous nature of this market means that other companies might be trading on the futures exchange without this being apparent to market participants.

There is a tension between retailers and generators with respect to the preferred time frame for contracts. Generally retailers prefer short time periods and are not much interested

---

<sup>8</sup>One NSW generator mentioned that State government requirement to get funds through the NSW Treasury Corporation made it expensive for them to operate in the SFE market where funding injections were required over time.

in signing contracts for more than a couple of years ahead as this is the longest horizon over which they have some clarity on load profiles and over which demand can be forecast with a reasonable accuracy. By contrast generators would be happy with longer term contracts to ensure a stable and guaranteed cash flow to recover their fixed costs of plants, and in the case of investment decisions for a new plant a long-term contract is essential for bank funding.

There are a number of factors that make it hard to predict what will happen in the future. Not only are there possible changes in the market brought about by regulators (e.g. changes in the state based schemes like ETEF, or new environmental instruments), but there could also be changes in the supply-demand balance with new generation capacity. From a retailer perspective this makes it risky to enter a long-term contract at a price that may turn out to be significantly too high. As one participant put it: *“Not too many people want to go out past three years, because the water is getting a bit murky out there.”*

Market participants, both retailers and generators, who are primarily hedgers will gradually build up their contract portfolios over time to manage price and volume risks as the market situation becomes less uncertain. For example, at one year out, they may want to be fully contracted (100% of final contract cover), two years out 60-70% contracted, three years out 20-30% contracted, and at four years out 5-10% contracted. But participants adopting this approach made it clear that this was a guide, around which they would vary considerably according to market conditions.

We also asked participants for an estimate of how much of their total contracts were in the form of swaps. Where specific figures were given (10 participants) they reported an average of 68% of contracts in the form of swaps (with the remainder equally split between caps and other options).

### **4.3 Hedging strategies**

There are risks associated both with pool price volatility and also with changes in system load (volume risk). Both retailers and generators are exposed to volume risks due to demand fluctuations, which are strongly correlated to weather conditions and usage patterns. Retailers in particular are at risk for the uncontracted load when the spot price goes high. Therefore, an accurate forecast of their own load is necessary in managing the volume risk. Generators' risk comes from a failure to meet their contracted supply due to planned or unplanned outages or network problems reducing their delivery of power to contracted customers.

To understand the nature of the strategies employed it is helpful to bear in mind that the price risk is not symmetric. The largest risk is associated with high prices, with occasional peak pool prices of \$10,000 per MWh (the price cap, which is called VOLL for Value of Lost Load) over against an average level (at a time of day with peak demand) of \$40 to \$50. Thus the distribution of prices is highly skewed and the risk is correspondingly one-sided. The other point to bear in mind is that generators differ substantially in their operating characteristics.

To illustrate the effect of a simplified hedging policy consider an example with two generators and one retailer. There is a base-load generator having four units each of size 150 MW and a peaking generator of size 150 MW. The retailer has a demand profile which varies according to the weather. Figure 2 shows the 95% load profile, the (median) 50% load profile and the 5% load profile for a particular day. This is the load that the retailer wishes to hedge. Suppose that the retailer has a flat swap contract with the base load generator for 300 MW at a price of \$35 per MWh and a peak swap contract for 150 MW at a price of \$50 per MWh. In addition he has a \$300 cap contract with the peaking generator for a further 100MW at a payment of \$5 per MWh. Thus the retailer pays a premium of \$500 per hour to have this contract, but receives  $\$100(p - 300)$  per hour if the pool price  $p$  is above \$300.

As the figure shows the net effect of this is that the retailer's 95% load profile is always covered with either swaps or caps. The \$300 cap only comes into play when the pool price goes higher than this - in the Australian market if this happens the price will frequently get to VOLL or near to it. This is the reason for the relatively high price for a cap which is so far above average price levels.

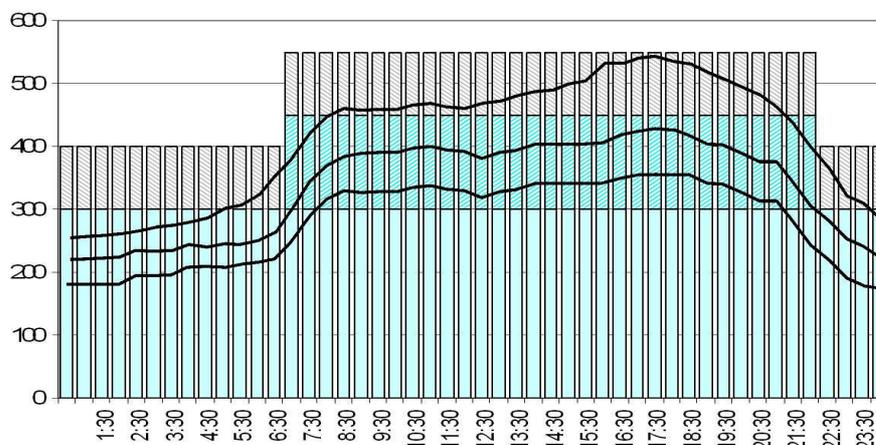


Figure 2: Load profiles and structured contracts

Consider the situation for the retailer for the half-hour starting at 17:30. The total swap cover is 450. On a median day load is 425. But on a 95% hot day the load is 540. The table below shows three scenarios for this half hour assuming that the retailer receives from its customers an energy payment of \$50 per MWh. Notice that since this is a half hour period, dollar amounts are divided by two.

Scenario	load (MW)	pool price	Retailer receipts:				Profit (loss)	
			Pool	Flat swap	Peak swap	Cap con- tract	Customer	
Average	425	\$48	-\$10,200	\$1,950	-\$150	-\$250	\$10,625	\$1,975
Hot	540	\$60	-\$16,200	\$3,750	\$750	-\$250	\$13,500	\$1,550
Extreme	570	\$9500	-\$2,707,500	\$1,419,750	\$708,750	\$459,750	\$14,250	-\$105,000

So, with this arrangement, the retailer has a sufficiently large amount of contract cover to make profits even on a hot day when pool prices are at \$60. If there is an extreme weather event and prices go to \$9500 per MWh at the same time as the retailer's load goes higher than its total cover (including \$300 caps), then the retailer will make a loss.

We can look at this situation from the generators' perspective. Suppose that the base-load generator usually operates 3 units during the night and 4 units during the peak period <sup>9</sup>. Holding these contracts with the retailer will essentially lock in a price for three of its units and leave just one unit exposed to variations in the pool price. This means that three of its generation units can be offered into the market at a low price, to ensure that they are dispatched, without the risk that pool prices are so low that it cannot recover its costs. For a generator that needs to keep a steady income stream this is very desirable.

Suppose that the peaking unit has relatively high running costs and can only make money if the pool price is more than \$80 per MWh. By signing a \$300 cap contract this generator has an income stream whether or not it is turned on (though it does not forego the opportunity of making a substantial profit, up to \$220 per MWh, when it is running). For this generator the risk is that pool prices never (or very rarely) become high enough to enable it to run, and the cap contract mitigates this risk.

This example illustrates how the retailer and base load generator are natural hedging counter-parties for swap contracts and the retailer and peaking generator are natural hedging counter-parties for cap contracts. However there are endless variations on the basic theme we have outlined, and we mention a few of them here.

---

<sup>9</sup>The peak period is defined as 07:00-22:00 on working days. The remaining time is offpeak.

- Swaptions can be used instead of caps - they have similar effects.
- Some retailers own peaking generation capacity - this is nearly equivalent to having a cap contract for the capacity of the generator. In a similar way some retailers have contracts enabling them to call up certain embedded generation facilities, like back-up units in big shopping centers.
- Some swap contracts are set up with a profile for each half hour of the day. This enables the retailer to more closely match its demand profile - we say more about these structured products below.

Retailers generally wish to have hedge cover which matches their load profile reasonably closely, leading to a requirement for shaped products. However a generator would prefer to have a flat profile, matching its likely generation capacity, and will charge more for the shaped product. This is because, when a generator sells a swap with tapered load at the shoulders of the demand profile, then it will be very hard to find potential buyers for the remainder of its capacity. There are however a variety of other structured products that might be more attractive to a generator and still have the desired outcome for a retailer. Some products mentioned by participants were:

- The shaped product may be defined in terms of the overall load in the system (at the generator's node), e.g. the swap quantity could be set to increase by 10 MW for each 50 MW of additional system load above some level.
- The swap may be activated with a trigger, so that it only becomes operational when system load is high or there is a high temperature event.
- The swap may contain a degree of 'optionality'. For example, for a call fee, a retailer may be able to nominate how much energy is required for a swap on a half hour by half hour basis. This would be negotiated with a time window, e.g. the nomination must be made at least 10 minutes before the start of the half hour. The retailer then exercises the swap only when a high load is anticipated, and a peaking generator has enough warning to start up, so that its physical generation matches the generator's hedge and it is protected from a price spike.

There is a degree of ambivalence in relation to shaped products. Some market participants believe that the higher price is not worthwhile. Retailers would do better to manage significant

risk associated with load profiles through derivatives instruments, rather than entering into complex deals with generators, which might take weeks to agree. Certainly one difficulty faced by retailers with significant contestable load is that large customers may be won or lost which can effect their anticipated load profiles at relatively short notice. Moreover overall trends in demand and updates on weather forecasts contribute to retailers wishing to fine-tune their contract cover as they move closer to real time. But a structured product is unique and there is no opportunity to adjust the profile of cover through the futures or broker-traded OTC market. Thus it may not be surprising that the total amount of structured product is limited with, from the responses we received, an average level being about 20% of structured product (though one generator commented on the increasing demand for profiled swaps).

It is possible to see the forward market as mechanism for allocating risk in the most effective way. Our discussion so far has concentrated on the risk positions of generators and retailers, but there is also a role for large consumers. This is an area in which the NEM is changing. Perhaps as a result of the activities of consultants a greater number of customers now seem prepared to carry some additional risk, through an increased exposure to spot prices, if this means a reduction in overall costs. This is particularly important for customers who have opportunities to shed load through changes in their operations. For large industrial customers (say greater than 5 MW) it has become commonplace for them to have contracts with a provision for load curtailment. Under this arrangement the retailer will contact the customer in the event of a price spike and ask them to reduce their load. Then the retailer and the customer share the net benefit according to the terms of the contract (perhaps on a 50:50 basis).

For example, given the extreme scenario in the example above, the retailer might suggest to a large customer that it shed load and be rewarded at half the difference between pool and its energy charge of \$50 a MWh. A customer who could reduce load by 5MW for half an hour would then receive a total of \$11,812, with the retailer gaining the same amount. If the overall system load was reduced enough for generators to be dispatched at a lower point on their bid curves then this load shedding arrangement might lead to a reduction in peak prices, in which case the gains to the retailer could be even greater. But leaving this effect aside, from the retailer perspective, load shedding operates as a partial cap.

Just as there is a risk to a retailer who is under-contracted when the spot price peaks, there can be a matching risk to a generator who is over-contracted when there is a price spike.

Provided a generator dispatches to the pool an amount that is at least equal to its contract position, then it has nothing to fear. Thus generators in their hedge books will not contract for more than their capacity. But a base load generator is at risk if it is fully contracted and there is an unplanned outage (i.e. a break-down of some sort) and at the same time the pool price goes very high (which is exactly what might happen if the outage causes supply shortages). In this scenario the generator could lose very large amounts of money. For this reason most generators are unwilling to be fully contracted. They often adopt an  $n - 1$  strategy which means that they contract only up the level that they can supply from all but one of their generation units - hence giving them protection provided no more than one of their units fails at the same time.

Of course, a strict  $n - 1$  strategy may not be suitable. For those generators with only a couple of units, it may not be a good strategy to leave one unit fully uncontracted. In this case, they may simply leave some proportion, say 25% of their total capacity not covered by contracts. For generators with many more units, they may leave more than one unit uncontracted. For example, a generator might have 8 base load units and leave 1.5 units uncontracted. This balance of risk will typically be considered carefully, often using some simulation methodology.

Nevertheless, even if this is the position for their hedge book, a generator may still decide to take on additional risk as part of its trading strategy, and choose to enter contracts greater than its installed capacity. Generators who do this may well trade outside the region in which they are located and may also be active in the SRA market (see below).

In market conditions in which there is a high demand for forward contracts from retailers there may well be a substantial price premium that encourages generators to become more fully contracted. There are a number of alternative ways in which a generator can try to moderate the risk of an unplanned outage:

- One possibility is simply to have an insurance contract, possibly with an intermediary like Westpac.
- Alternatively a generator may have contracts of some sort with other generators to take over the capacity that they have contracted but cannot meet during their outage period. These are natural counter-parties for this risk, since an outage at one generator will be likely to result in higher prices and higher demand for other generators.

- A third possibility is to use a *force majeure* (FM) clause in the contract, so that the contract does not operate in the event of the generator being unable to supply. FM clauses used to be widely used in Victoria, but most retailers state that they do not want these clauses included in their contracts. However, participants report that FM clauses are still in use in some bilaterally negotiated, large contracts in Queensland, SA and Victoria. In some cases a type of FM clause is used that only comes into play when a generator is unable to supply through line or network problems (thus excluding generator faults). In other cases an FM clause may be signed in a contract between a generator and retailer if a large industrial customer decides that they will wear this risk for the benefit of a lower price.

In some other markets (see Energy Information Administration Report (2002)), insurance and contracts with multiple triggers are used to manage forced outages. For example, a double-triggered contract may be exercised when a forced outage has occurred and the market price has exceeded the preset level.

Outages can be of many types. In the case of planned outages for maintenance there will be a schedule that goes out for 2 years or more. This allows enough time to adjust contract cover for the period in question. However there are circumstances when a generator is obliged to take a generation unit out with only a short warning (days or weeks). As we mentioned earlier, in this case a lack of short-term liquidity may force the generator to approach other market participants for a short-term contract on a bilateral basis, when the price is likely to be quite high.

From the interviews we carried out it seems that on average base load generators are about 70-80% contracted. This can be compared with Table 2 which gives estimates of aggregate contract covers in various markets. Note that PJM, New England and New York all have vertically integrated generation and retail businesses. Generators in the UK also have their own associated retail arms.

#### **4.4 Setting the contract price**

Contract agreements are reached through bilateral negotiation, with retailers more often initiating the contracts and approaching the generators, rather than vice versa. This happens because of the asymmetric form of the price distribution, and the risk of price spikes - broadly speaking a retailer cannot afford to be under-contracted, whereas a generator cannot afford

Pool Market (year)	NZEM (1999)	UK	PJM (2001)	CAISO (2001)	NEISO(2004)	NYISO(2002-2004)
contract level (%)	80 <sup>a</sup>	95 <sup>b</sup>	82 <sup>c</sup>	90 <sup>d</sup>	73 <sup>e</sup>	82-92 <sup>f</sup>

<sup>a</sup>Business Activity Statistics (1999)–reference report, New Zealand, June 2000.

<sup>b</sup>Introduction to the UK electricity market, Electricity Association, 2002.

<sup>c</sup>in PJM, participants have two options: bilateral contracting or bidding to the spot market. Only 28% of trading volumes are through the spot market according to Byrne and Yu (2005). All major generators are vertically integrated with their retail arms.

<sup>d</sup>of their "net short" positions, and they normally have more than 60% of the load covered by their own capacities or contracts predated the restructuring started in April 1998, see Borenstein (2002)

<sup>e</sup>New England ISO, 2004 Annual Markets Report, ISO New England Inc, 2005

<sup>f</sup>New York ISO, 2004 State of the Market Report

Table 2: Level of contract covers in overseas markets

to be over-contracted. However, once a relationship has been established, the generator and retailer may talk to each other on a regular basis regarding contract issues. As the retailers know their load profiles and have information on interruptible load, they are able to design specific structured products and then take these products to generators to negotiate contract prices. It is interesting, however, that one generator commented on reducing levels of direct contacts with retailers, as the use of brokers increases.

The contract price is obviously critical, but how do the counter-parties agree a strike price for their contract? We found that participants bore in mind a number of factors. The starting point is to ask what is the market price for a contract. Since the majority of contracts are signed bilaterally this information is not public, which makes it harder to find the right price. The Australian Financial Markets Association (AFMA) publishes electricity forward curves based on a poll of NEM participants' opinions and brokers may provide additional price analyses as well. In addition, the SFE's bid/ask spread provides price guidance. However some participants indicated that the AFMA forward curve can be misleading, and price discovery either through the SFE or through offers appearing on brokers screens, is problematic, partly because the market is illiquid in the longer term. Some retailers mentioned that for the price discovery purpose, they may split the quantity that they want to contract between the different channels available. Generators may also want to diversify their contracts among different counter parties, but for credit risk reasons.

Another complicating factor in pricing direct bilateral contracts, is that they are often for significantly larger volumes than for contracts through brokers. There are two alternative and opposing views on what this does to the price. Retailers may argue that there should be a

further discount on the price associated with the large quantity. In this context a discount can be seen as reflecting the cost of the risk that a generator runs in trying to build up the same position over time through smaller trades. An alternative (generator) view is that the retailer should pay a price premium for the larger quantity of hedge. Even if a lower price is available for, say a 10MW contract through a broker, if the retailer keeps going back to the brokers' screens for trades, then the price will rise after the first few deals as generators respond to the increased demand for this particular product.

Alongside the view of the 'going rate' for a particular contract, represented by some combination of recent deals done, bid/ask spreads and the AFMA forward curve, market participants will also hold their own view of the correct price for that contract. This is related to what they expect to happen to the forward curve in the future. The most important underlying factors are the available supply and demand. Thus a trader will compare the market price with his or her own estimation of where this price will move in the future to decide whether to accept it. Most of the time traders have some flexibility to delay or bring forward the contracts they are signing for a particular period in the future.

The ability to choose the time at which a contract is signed is limited, however. Since all market participants are working within well-defined limits for certain risk measures, they may find themselves forced to change their contract position with relatively little notice. Moreover the necessity to end up with a solid hedge position will force participants to sign contracts for a given period as that period approaches. This brings into play the issue of the supply and demand for contracts. The hedge requirements from both sides of the market drive this contract supply-demand balance. Thus if the retailer demand for flat or structured product is greater than the generator willingness to supply, then contract prices are pushed up and generators will look again at their risk position with respect to outages and may decide to sell more contracts, perhaps using some of the methods mentioned in the previous section to deal with the outage risk. One participant described this as the situation in NSW at the time of this study: *"Generators are getting to the envelope of where they really want to sell at"*.

It is noticeable that participants give varying responses to questions about their use of FM clauses, in a way that reflects the contract supply and demand balance. Having fallen out of use during recent years as the supply position has been relatively benign, a couple of participants mentioned their willingness to consider FM clauses, specifically as a way of achieving a higher degree of contract cover at times when there was a shortage of generator

contract capacity.

Setting prices for very long-term contracts poses particular difficulties. Whatever the varying limitations of different estimates of the forward curve, no one has any confidence in being able to predict this more than 4 to 5 years out. When new generation capacity is built it is necessary to look at funding over a period of 15 to 20 years. Over this time horizon pricing becomes a matter of a generator recovering costs and making a reasonable return. Hence contract prices are based on calculations of capital and operational expenses. Whatever the time span for the contracts, in price discussions generators will be acutely aware of how much they need in order to cover their financing requirements, and generators likewise will try to lock in a margin against the retail price they charge.

The price volatility of an underlying commodity or financial instrument is often used in academic literature (see Energy Information Administration Report (2002), Eydeland and Wolyniec (2003), Pindyck (2001)) as an indicator of market risk. Therefore the contract price in a more volatile period may be higher than that in a less volatile period. This is evidenced in our interviews. In fact, a number of participants told us that they model and closely monitor the volatility of the spot market prices. Based on this perception, generators may bid in a strategic way to increase the volatility of spot market prices in order to push up the price in the contract market.

The spot market price influences expectations of the spot price in the future and will have an impact on forward contract prices. However, looking at the market data shows that the connection between spot and forward prices is not straightforward or immediate. There can be difficulty for someone outside the market in understanding the underlying cause for occasional significant changes in forward contract prices.

There is some controversy over the extent to which a price premium in the contract market reflects just a risk premium, or whether it also includes an incentive for generators to enter contracts that will effectively limit their market power in the spot market (see Anderson and Hu (2005), Powell (1993)). The retailers were asked whether they agreed with the statement: Contract prices are higher than the average spot price, but if contracts were not signed then spot prices would rise. All but one of the retailers answered “yes”. One retailer stated: *“Sometimes you will get a new board member [argue that] our average contract rate last year was \$40 and the average spot was only \$27 why didn’t we just take the spot? And we say yes, but it wouldn’t be \$27 if we weren’t contracted.”*

It is widely recognized that there have been significant changes in the relationship between contract and pool prices during the history of the NEM. In the early stage of the NEM pool prices were significantly lower than the price of vesting contracts. For example, in 1999 the volume weighted average spot market price in NSW was \$24.42/MWh; while the price of vesting contracts for Type 1 customers (80% of the vested load) in NSW for 1999 was \$37/MWh<sup>10</sup>. See also Wolak (2000) for a discussion of the situation in 1997 for the NSW and VIC pools from which the NEM developed. This resulted in a drop in contract levels, as retailers took the view that the prices for swap contracts were too high. However this in turn led to much higher pool prices as generators sought to maximise their profits (the average VIC pool price went from \$26.35 in financial year 1999-2000, to \$44.57 in the following year), with the result that retailers, particularly in Victoria, ended up doing badly during this period as they paid high prices without much contract cover. Market participants have become more sophisticated and we would not expect to continue to see such large swings in the contract price vis-a-vis the spot price.

What has been happening in recent years? Table 3 gives the spot average prices and AFMA mean forward prices for the week prior to the beginning of the calendar year of the contract (where we would expect the smallest difference between contract and spot prices). For the majority of cases forward prices are higher than spot prices (with only 5 out of 48 cases where the reverse is true). The average premium over the 4 regions and 3 years is \$9.09 for the peak period (NSW has an average contract price \$2.24 lower than spot, while the premium in the other states was \$11.34 in QLD, \$13.68 in SA and \$13.56 in VIC). The premiums for the offpeak periods are smaller, averaging \$2.85. This can be explained by observing that competition is stronger in the off peak periods, so that the moderating effect of contracts on market power is not significant, or the explanation may be simply related to a higher price volatility in the peak periods, leading to a greater risk premium.

It is possible that the operation of the ETEF is significant in the way that the NSW contract prices have not shown the same premium to spot prices as in other states. The ETEF gives an effective hedge for retailers and this means that they do not need to seek contract cover for the franchise portion of their load. Hence the demand for contracts in NSW is lower than it would be otherwise, which will contribute to relatively lower contract prices in

---

<sup>10</sup>Source: ACCC Decision on NSW electricity vesting contracts, Release no. MR 164/99 and release date: September 2, 1999.

		NSW		QLD		SA		VIC	
		Forward	Spot	Forward	Spot	Forward	Spot	Forward	Spot
2003	peak	50.01	35.54	49.94	29.41	56.25	34.50	54.42	30.86
	offpeak	24.16	19.05	24.62	17.03	24.84	20.40	23.48	16.86
2004	peak	45.47	65.19	41.44	46.94	54.19	52.47	43.01	38.91
	offpeak	32.11	29.09	20.09	24.56	23.85	32.97	29.95	22.93
2005	peak	52.66	54.13	53.30	34.31	61.78	44.21	47.01	33.98
	offpeak	25.22	21.25	23.38	17.91	28.20	25.18	22.37	20.81

Table 3: Average spot prices and forward prices in NSW, QLD, SA and VIC

this state (given the reluctance of participants to sign contracts across regions that we mention below). But there may also be an effect on spot prices. When the ETEF fund is at a low level, generators may need to top up the ETEF fund if prices in the pool go high - in this situation the ETEF has a moderating effect on the exercise of market power, in a similar way to the hedge contracts it replaces. But when the ETEF fund is at a high level there is no dampening effect on prices in the spot market. Some participants believe that NSW generators have bid higher prices into the pool when the ETEF fund has a large sum built up in it.

We did not explicitly ask about the influence of individual market players on prices in the spot market. Nevertheless this issue was mentioned by some participants, with the majority taking the view that the market is not fully competitive (i.e. that generators are able to exercise market power). For example one generator referred to the tension between bidding in a way that maximized immediate return and bidding in a way that would lead to higher contract prices, enhancing long-term profitability.

Almost all market participants use analysts to model the price dynamics in order to price options appropriately. Some mentioned specific derivatives pricing models they used like the Black-Scholes models and spikes-driven jump-diffusion models (for more on derivatives pricing models used in energy markets, see Eydeland and Wolyniec (2003)).

#### 4.5 Location risk and settlement residue auctions

In markets where locational marginal prices are implemented to reflect congestion (e.g. the PJM and the New England Pool), then the payment received by the market operator from the energy buyers may not be in balance with that paid to energy sellers. The difference is called a *congestion rent*. Financial transmission rights (FTR) (Gedra (1999), Hogan (1992)) are used to hedge the price differences at the delivery and receiving nodes and allocate the congestion

rent. The FTR is a point-to-point transmission right. An alternative approach, which is incorporated into the Standard Market Design proposed by the Federal Energy Regulatory Commission, is to use flowgate rights (see Chao *et al.* (2000)), which are financial rights that can operate on a group of lines.

In NEMMCO's pricing and dispatch engine (NEMDE), network constraints and (approximated) losses are considered. These two factors are the sources of a potential difference between the amount received by NEMMCO and the amount paid out, which is called the settlement residue (SR). NEMMCO holds quarterly auctions to assign the rights of receiving a share of the inter-regional settlement residue (IRSR). The Settlement Residue Auction (SRA) in the NEM is a little similar to an FTR auction, since the SR allocation is based on the regional reference nodes, not on particular lines/routes connecting the regions. The SRA assumes a single notional interconnector between regions. For example there are two regulated interconnectors between SA and VIC (see Figure 1), but only one notional interconnector for SRA purposes. The available units in a particular notional SRA interconnector are roughly at the level of the nominal inter-regional transfer capability in MW between these regions.

The design of the SRA is intended to encourage inter-regional trading, therefore increasing competition, and provide an opportunity to hedge inter-regional price differentials. However, there is no clear consensus among academics about whether financial transmission products actually increase competition (e.g. Stoft (1999)).

Each SRA participant submits a set of bids to NEMMCO: bids are pairs of prices and numbers of units over (possibly linked) directional notional interconnectors. The higher price bidder will win the units available for the specific direction in question until all available units have been allocated. The clearing price for the directional link is the lowest bid price amongst the winning bids. The available units of each notional interconnector for each calendar quarter are auctioned in four equal tranches. The first tranche auction for the units of a given quarter (say Quarter 3 2006) is held in the same quarter but a year ahead (i.e. Quarter 3 2005). The second tranche auction is held in the following quarter, and so on<sup>11</sup>.

Table 4 gives details of the auction results for a particular quarter for the connectors both in and out of NSW. The IRSR distributed is the IRSR less the auction fees charged by NEMMCO if this number is positive, and the average IRSR reward is the net earning per

---

<sup>11</sup>The revenue from the SRA for each directional interconnector will go to the corresponding transmission network service provider in the importing side.

	NSW→SN	SN→NSW	QLD→NSW	NSW→QLD
clearing price (T1, \$/unit)	56.00	3200.00	4325.00	1074.00
clearing price (T2, \$/unit)	86.00	4000.00	4938.90	2465.00
clearing price (T3, \$/unit)	105.60	4008.00	5002.00	999.00
clearing price (T4, \$/unit)	157.00	4750.00	5250.00	651.00
available units (Q3 2005)	800	2500	1000	500
auction proceeds(\$, Q3 2005)	80920.00	9973750.00	4878975.00	648625.00
IRSR distributed(\$, Q3 2005)	55222.62	1243511.02	11057925.74	0.00
average IRSR reward (\$/unit)	69.03	497.40	11057.93	10.00 <sup>a</sup>

Source: NEMMCO's Auction Reports 2005-2, 2005-3, available on its website

<sup>a</sup>All SRA auction winners are guaranteed a minimum payment of \$10/unit by the SRA rules.

Table 4: SRA clearing price, purchase payment and reward for July-September 2005 into and out of the NSW region

unit. As we can see from the table, the unit payment from the IRSR back to the purchasers of the (financial) transmission right for interconnectors: NSW→SNOWY, SNOWY→NSW and QLD→NSW, are much lower than the purchase prices. The net payments to NEMMCO from these purchasers may be seen as premiums for cap-type contracts if they have inter-regional contracts. From QLD→NSW, one may see opportunities to make money out of the SRA in this quarter.

Consider a generator in Queensland who signs a swap contract for an amount of 100 MW for 2007 Quarter 1 with a retailer in NSW at a strike price of \$40 per MWh based on the NSW regional price. Thus if the price in NSW is \$45 then the generator will pay an amount of \$500 per hour to the NSW retailer (and the other way round if the price is \$35). However this leads to the generator having no hedge against any price difference between the NSW and Queensland price. If the price becomes very high in NSW and remains low in Queensland then the generator will need to make a large payment in relation to the contract without receiving a large payment for its own spot market generation. However if this does happen then it will imply that there should also be a flow of power on the Queensland to NSW links. In fact the generator would anticipate these links being full and the system operator collecting an amount given by the product of the price differential between the two regions and the capacity of the interconnectors. So a bid in the SRA allows the possibility of making good this loss.

In theory we could expect to see speculators driving the cost of a unit in the SRA towards its true expected value, and participants who hold swap contracts outside their region participating in the SRA, and being prepared to pay a premium because of the value of the hedge they will obtain if their purchase is successful.

However the SRA mechanism has a number of disadvantages and is a relatively crude instrument to use in hedging inter-regional risk. The key problem is that a large price differential between two regions may occur when the link is not operating at full capacity (either through an outage or because of more complex factors associated with the network). In these cases there will be a much reduced settlement residue, but the market participant is still exposed to losses through the price differential. In addition to this, auctions take place only at prescribed times and at a maximum of one year ahead. This means that the SRA cannot give an immediate hedge capability at the same time as the swap contract is entered into. Moreover the SRA does not have any flexibility to hedge different load profiles (unless we take the view that the great majority of Settlement Residue payments are associated with peak demand, enabling it to be used to hedge a peak load contract).

Our survey reveals that the SRAs do not operate effectively in encouraging interregional trade. Almost all the participants said that they tried to arrange contracts between counterparties in the same region, so as not to be exposed to inter-regional trading risks. Where these 'basis' risks were taken on, the participants often hedged them through an interregional product (a swap based on the difference between nodal prices) rather than through an SRA and many participants stated that they were not actively involved in the SRA. It seems that a significant part of the trade in SRAs is within the participants' trade books and is speculative rather than carried out for hedging purposes.

## **5 Trends in the market**

The Australian electricity market continues to evolve. In common with the Californian and England and Wales markets, it was set up with a separation between generation, transmission, distribution and retail companies. However there is no legislative restriction on cross-ownership, provided it is not deemed to be anti-competitive. As a result there has been some consolidation of the industry through acquisition or mergers, with ongoing discussion of further moves in this direction. The most common pattern has been for retailers to purchase peak or intermediate generation capacity. At the moment this stops well short of the inte-

gration of generation and retail on a regional basis (as is the case with many US markets in which generation and retail businesses remain integrated). Nevertheless many in the industry wonder whether further moves towards vertical integration are becoming almost inevitable, perhaps following the pattern of the UK electricity market. Vertical integration has the effect of reducing the need for hedging contracts. Thus a retailer who owns peaking generation capacity will operate this capacity whenever pool prices are higher than its running cost.

In tandem with changes in overall market structure there has been an evolution in the contract market. This has been primarily a result of market participants becoming more confident in operating within this market. Many participants have increased the size of their trade portfolios (in addition to their hedging contracts). Some participants mentioned that they were more prepared to manage the risk themselves, rather than see this as something to be passed on to a third party or intermediary. This increased level of sophistication can lead to a preparedness to act as a price maker in this market, rather than a price taker. It may also lead to a demand for more sophisticated derivative products. Note that many of the traders in the contract market have experience in trading in other commodities. When the financial side of the NEM first began it had a very different flavour, with more of a “procurement” approach to the discussions between generators and retailers.

Looking to the future, changes in the structure of the market place represent a regulatory risk that market participants need to absorb. Almost all participants see the regulatory risk at both the federal and state government levels as the largest risk they face and they look forward to a clear, stable and consistent regulatory policy system.

Our study has shown that a significant issue facing the contract market in Australia is the lack of liquidity. Liquidity has been a concern in many secondary financial market for electricity, primarily due to the fact that the underlying markets are not perfectly competitive. The illiquidity in the Australian market is reflected in relatively large bid-offer spreads. From the perspective of the Australian market the critical liquidity issues concern OTC trades through brokers and trade on the SFE. It is interesting that there are few intermediaries or speculators in this market: to some extent their place is taken by the trading operations of generators and retailers (who operate both a trade book and a hedge book). Participants in the market would benefit in a number of ways from a more liquid market. This could help them reduce hedging costs through the availability of a better range of products, and through being better able to adjust their contract positions in the light of changes in forecast load

(for a retailer), or equipment availability (for a generator). It may also help in improving the handling of credit risk and in the evaluation of risk positions using mark-to-market methods.

The history of energy futures trading in Australia had a slow start, with low volumes in the early years of SFE energy futures trading and with the energy futures trading at the Australian Stock Exchange never reaching significant volume. The UK market experienced similar difficulties in the early stage of the NETA<sup>12</sup>. It is interesting to compare the Australian experience to that of the Nord Pool, where, since 2003, futures contracts have only existed for the short-term (8-9 weeks ahead) with all other contracts (up to 4 years ahead) being traded as forwards. It seems that in the Nord Pool the preference for using the futures exchange for short-term products is due to the relatively high expense of working with daily settlements for long-term products.

There have been some improvements in liquidity over the last few years. The SFE has recorded strong growth in futures trading in the period since 2005. Also some new participants (speculators) are reported to be entering the market. However a number of participants are concerned that moves towards vertical integration will significantly reduce liquidity.

## Acknowledgement

The authors would like to thank all the participants in the survey. We are especially grateful for their openness and patience in answering our questions.

## References

Allaz, B. and J.-L. Vila (1993). "Cournot competition, futures markets and efficiency." *Journal of Economic Theory* 59:1–16.

Anderson, E. J. and X. Hu (2005). "Strategic retailer behavior in an electricity contract market." *Australian Graduate School of Management, Working paper. The University of New South Wales.*

Anderson, S. C. (2004). *Analyzing strategic interaction in multi-settlement electricity markets:*

---

<sup>12</sup>At the start of NETA in 2001 there were three major exchanges where electricity futures were traded: the UK Power Exchange (UKPX), the UK Automated Power Exchange (APX) and the International Petroleum Exchange (IPE, now Intercontinental Exchange–ICE). In June 2004, the UKPX was combined with the APX and this is now the dominant exchange (with UK power futures being only a very small proportion of the ICE).

- A closed-loop supply function equilibrium model.* PhD thesis, Harvard University, Cambridge, Massachusetts.
- Bessembinder, H. and M. L. Lemmon (2002). “Equilibrium pricing and optimal hedging in electricity forward markets.” *The Journal of Finance* 57:1347–1382.
- Borenstein, S. (2002). “The trouble with electricity markets: understanding California’s restructuring disaster.” *Journal of Economic Perspectives* 16:191–211.
- Bushnell, J. (2005). “Oligopoly equilibria in electricity contract markets.” *CSEM WP 148, University of California Energy Institute.*
- Byrne, J., Y.-D. Wang and J.-M. Yu (2005). “Lessons from a comparative analysis of California and PJM electricity restructuring models.” *Center for Energy and Environmental Policy, University of Delaware.*
- Chao, H.-P., S. Peck, S. S. Oren and R. Wilson (2000). “Flow-based transmission rights and congestion management.” *Electricity Journal* 13:38–58.
- Energy Information Administration Report (2002). *Derivatives and risk management in the petroleum, natural gas, and electricity industries.* U.S. Department of Energy, Washington D.C..
- Eydeland, A. and K. Wolyniec (2003). *Energy and Power Risk Management—New Developments in Modeling, Pricing, and Hedging.* John-Wiley & Sons, New Jersey.
- Gedra, T. W. (1999). “On transmission congestion and pricing.” *IEEE Transactions on Power Systems* 14:241–248.
- Green, R. (1999). “The electricity contract market in England and Wales.” *Journal of Industrial Economics* 47:929–952.
- Hogan, W. W. (1992). “Contract networks for electric power transmission.” *Journal of Regulatory Economics* 4:211–242.
- Hu, X., G. Grozev and D. Batten (2005). “Empirical observations of bidding patterns in Australia’s National Electricity Market.” *Energy Policy* 36:2075–2086.
- Klemperer, P. D. and M. A. Meyer (1989). “Supply function equilibria in oligopoly under uncertainty.” *Econometrica* 57:1243–1277.

- Lucia, J. and E. Schwartz (2002). "Electricity prices and power derivatives: Evidence from the Nordic power exchange." *Review of Derivatives Research* 5:5–50.
- Michaels, R. J. and J. Ellig (1999). "Electricity: price spikes by design?" *Regulation* 22:20–22.
- Moulton, J. S. (2005). "California electricity futures: the NYMEX experience." *Energy Economics* 27:181–194.
- Newbery, D. (1998). "Competition, contracts, and entry in the electricity spot market." *RAND Journal of Economics* 29:726–749.
- NSW Treasury (2001). "A risk management proposal for New South Wales' electricity businesses." *Discussion paper (December 2001), Further consultation paper (May 2004), Sydney, Australia.*
- Pedersen, S. S. and B. Mo (2005). "Risks and risk management for competitive electricity markets, report from CIGRE TF C5-2.02." *CIGRE/IEEE PES, International Symposium, October 2005*:156–163.
- Pindyck, R. S. (2001). "The dynamics of commodity spot and futures markets: a primer." *The Energy Journal* 22:1–29.
- Powell, A. (1993). "Trading forward in an imperfect market: the case of electricity in Britain." *Economic Journal* 103:444–453.
- Shawky, H., A. Marathe and C. L. Barrett (2003). "A first look at the empirical relation between spot and futures electricity prices in the United States." *The Journal of Futures Markets* 23:931–955.
- Stoft, S. (1999). "Financial transmission rights meet cournot: how TCCs curb market power." *The Energy Journal* 20:1–23.
- Wolak, F. A. (2000). "An empirical analysis of the impact of hedge contracts on bidding behaviour in a competitive electricity market." *International Economic Journal* 14:1–40.